DIRECT TESTIMONY OF

JAMES W. NEELY

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2019-2-E

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Neely and my business address is 220 Operation Way, Cayce, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by SCANA Services, Inc. as Senior Resource Planning Engineer.

Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE PLANNING IN YOUR CURRENT POSITION.

A. I am responsible for modeling SCE&G's electric system for the purpose calculating avoided costs, determining the least cost resource plan, forecasting fuel costs, and evaluating changes to electric generation.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Clemson University with a Bachelor of Science degree in electrical engineering. From the Southern Wesleyan University, I received a Master of Arts degree in management in 2002. I was employed by SCE&G as a design engineer at V.C. Summer Station from 1992 to 1997. In 1997 I went to work in the SCE&G Resource Planning department as a resource planning engineer. In 2013 I was promoted to Senior Resource Planning Engineer.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss the resource plan study that describes the various generation planning scenarios analyzed and to present the resource plan on which avoided costs calculations are based.

I will also discuss SCE&G's avoided costs for power purchases under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). The short-run avoided costs for qualifying facilities ("QFs") that have power production capacity less than or equal to 100 kilowatts ("kW") are set forth in Rate Schedule PR-1 attached to Witness Rooks' testimony as Exhibit No. __ (AWR-14). The long-run avoided costs for solar QFs that have production capacity greater than 100 kW and less than or equal to 80 megawatts ("MW") are set forth in Rate Schedule PR-2 attached to the Direct Testimony of Company Witness Allen Rooks as Exhibit No. __ (AWR-16).

RESOURCE PLAN STUDY

Q. HAS SCE&G CONDUCTED A RESOURCE PLANNING STUDY?

A. Yes. My department performed a resource planning study for SCE&G. This study titled "Developing a Resource Plan," a copy of which is attached as Exhibit No. __ (JWN-1), shows nineteen resource plans evaluated under four different sets of assumptions. The study determined the current resource plan as set forth in the Company's Integrated Resource Plan filed with the Commission on February 8, 2019, and in Table 1 of Exhibit No. ___ (JWN-1).

Q. WHAT SCENARIOS WERE CONSIDERED IN DEVELOPING SCE&G'S CURRENT RESOURCE PLAN?

A. SCE&G considered the nineteen scenarios when developing the current resource plan. The scenarios are displayed in Table 1 below and discussed in more detail in Exhibit No. __ (JWN-1). Please note that "CC" is shorthand for Combined Cycle, "ICT" is shorthand for Internal Combustion Turbine, and "PPA" is shorthand for Power Purchase Agreement.

Table 1

Scenario Number	Scenario
1	Battery-1
2	Battery-1 w/ Solar Ownership
3	Battery-2
4	Battery-2 w/ Solar Ownership
5	CC 1081 MW
6	CC 540 MW + Retire Coal
7	CC 540 MW x2
8	CC 540 MW w/ Battery-1
9	CC 540 MW w/ Battery-2
10	CC 540 MW w/ ICT 337 MW
11	CC 540 MW w/ ICT 93 MW
12	ICT 337 MW
13	ICT 93 MW
14	Solar Ownership w/ ICT 93 MW
15	Solar Ownership w/ ICT 93 MW + Retire Gas
16	Solar PPA 200 MW w/ ICT 93 MW ($30)
17	Solar PPA 400 MW w/ ICT 93 MW ($30)
18	Solar PPA 400 MW w/ ICT 93 MW ($35)
19	Solar PPA 400 MW w/ ICT 93 MW ($40)

Q. WHAT ASSUMPTIONS WERE CONSIDERED IN DEVELOPING SCE&G'S CURRENT RESOURCE PLAN?

A. SCE&G considered four sets of assumptions when developing the current resource plan, 1) Base Gas Prices with Zero CO_2 Costs, 2) High Gas Prices with \$15/ton CO_2 costs, 3) High Gas Prices with Zero CO_2 Costs, 4) Base Gas Prices with \$15/ton CO_2 Costs.

Q. HOW WAS THE CURRENT RESOURCE PLAN SELECTED?

A. Base gas prices and zero CO_2 costs were used to select the current plan. Base gas prices is the most likely gas scenario and CO_2 costs are uncertain at this point. Even though this plan is selected for modeling purposes, no decision on future generation has been made. We will continue to analyze resource plans for several more years before making a decision to build new generation.

AVOIDED COSTS UNDER PURPA

Q. WHAT DOES PURPA REQUIRE?

A. PURPA and its implementing regulations require electric utilities, including SCE&G, to purchase electric energy from qualifying small power production facilities and QFs at the utilities' avoided costs. However, state public utility commissions, such as the Commission, determine the method for calculating avoided costs.

Q. WHAT ARE AVOIDED COSTS?

A. PURPA regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). The Federal Energy Regulatory Commission ("FERC") further recognizes that avoided costs include two components: "energy" and "capacity." Specifically, "[e]nergy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of* 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) ("Order No. 69"). In Order No. 81-214 and subsequent decisions, the Commission has recognized that utilities are entitled to recover their avoided costs under PURPA.

Q. WHAT APPROACH DOES SCE&G TAKE TO CALCULATE THE ENERGY AND CAPACITY COMPONENTS OF AVOIDED COSTS?

A. As approved by the Commission in Orders No. 2016-297 and 2018-322(A), SCE&G uses a difference in revenue requirements methodology to calculate both the energy component and the capacity component of its avoided costs. This approach follows directly from PURPA's definition of avoided costs in that it involves calculating the revenue requirements between a base case and a change case. The base case is defined by SCE&G's existing fleet of generators and the hourly load profile to be supplied by these generators, as well as the solar facilities with which SCE&G has executed a power purchase agreement. The change case is the same as the base case except that the hourly loads are reduced by a 100 MW solar profile, which is the maximum reduction allowed by PURPA regulation 18

C.F.R. § 292.302(b)(1) for utilities with systems larger than 1,000 MW of generation such as SCE&G. Using a carefully constructed computer program called PROSYM, which models the commitment and dispatch of generating units to serve load hour-by-hour, SCE&G estimates the production costs that result from serving the base case load. A change case is derived from the base case by subtracting an appropriate 100 MW solar power purchase profile. Then, as with the base case, PROSYM is used to estimate the production costs that result from serving the change case. The avoided energy cost is simply the difference between the base case costs and the change case costs. The avoided capacity cost is the difference between the incremental capacity costs in both its base resource plan and the change plan.

Q. WHAT PERIOD OF TIME DOES THE COMPANY USE TO CALCULATE ITS AVOIDED COSTS?

A. The short-run avoided energy costs are calculated for the period May 2019 through April 2020. The long-run avoided costs are calculated for calendar years 2019 through 2033, which is the time period appropriate for SCE&G's 2019 15-year Integrated Resource Plan ("IRP") planning horizon pursuant to S.C. Code Ann. § 58-37-40. These 15-years are divided into three groups of five years each: 2019-2023, 2024-2028, and 2029-2033.

PR-2 RATE

Q. BASED ON THE COMPANY'S APPROVED METHODOLOGY, WHAT ARE SCE&G'S AVOIDED ENERGY COSTS FOR THE PR-2 RATE?

A. Table 2 below contains the avoided energy costs for the PR-2 rate.

Table 2
Solar QF Avoided Energy Costs ($/kWh)

Time Period	Annual
2019-2023	$0.02384
2024-2028	$0.02317
2029-2033	$0.02826

Q. HOW DOES SCE&G CALCULATE ITS AVOIDED CAPACITY COSTS RELATED TO SOLAR FACILITIES ON THE COMPANY'S PR-2 RATE?

A. SCE&G takes a similar approach to developing avoided capacity costs as it does with avoided energy costs. Using the difference in revenue requirements methodology approved by the Commission in Order No. 2016-297, SCE&G calculates the difference in the revenue requirement between the base case and the change case. Using the resource plan in its latest IRP or an updated resource plan if appropriate, SCE&G calculates the incremental capital investment related revenue required to support the existing resource plan. As with its calculation of avoided energy costs for solar, SCE&G derives a change case in its resource plan by considering the impact of a QF purchase from a 100 MW solar facility.

Q. USING THIS METHODOLOGY, WHAT ARE THE AVOIDED CAPACITY COSTS FOR THE PR-2 RATE?

A. SCE&G currently has approximately 1,048 MW of solar capacity under PPAs and the addition of another 100 MW of solar has no effect on the resource plan. Stated differently, given the amount of solar generation that is currently projected to be interconnected to SCE&G's system, adding additional blocks of 100 MW of solar generation does not affect the Company's future capacity needs. For this reason, the avoided capacity costs of solar reflected in the PR-2 rate is zero.

Q. WHY DOES ADDITIONAL SOLAR CAPACITY NOT AFFECT SCE&G'S FUTURE CAPACITY NEEDS?

A. SCE&G performed a study that analyzed the impact of solar on its daily peak demands. This study titled "The Capacity Benefit of Solar QFs 2018 Study," a copy of which is attached to the Direct Testimony of Company Witness Dr. Joseph M. Lynch as Exhibit No. __ (JML-1), shows that solar has no effect on SCE&G's daily peak demand during a large majority of the days in the winter months of October through March. This is primarily because the winter peak occurs either early in the morning before solar begins to generate energy or in the evening after solar is no longer generating.

SCE&G's need for capacity is driven by the winter season. Because solar does not provide capacity during the winter period, the Company is unable to avoid any of its projected future capacity needs and, therefore, the avoided capacity cost of solar for these winter months is zero.

Q. WHY DOES SCE&G LIMIT ITS EVALUATION OF AVOIDED COSTS TO THE 15-YEAR PLANNING HORIZON OF ITS IRP?

A. It is important to recognize that future projections are uncertain. For avoided energy costs, it is not clear whether the projected costs over the last 5 years of the IRP planning horizon are too high or too low for those 5 years, let alone the 5 or 10 years beyond. Therefore, using projected costs beyond the 15-year planning horizon would be unreasonably speculative and would increase the costs paid by SCE&G's customers.

Q. DOES THE AVOIDED COST CALCULATION INCORPORATE A PORTION OF THE VARIABLE INTEGRATION COSTS?

A. Yes. The avoided cost calculation contains $0.00097/kWh of variable integration costs that will be deducted from the variable integration cost calculation set forth in the Direct Testimony of Company Witness Dr. Matthew W. Tanner and in the proposed Rate PR-2 tariff attached to the Direct Testimony of Company Witness Mr. Allen Rooks as Exhibit No. __ (AWR-16).

Q. HOW WILL SCE&G ADDRESS AVOIDED COSTS FOR NON-SOLAR QFs OF GREATER THAN 100 KW AND UP TO 80 MW?

A. SCE&G plans to negotiate contracts with any non-solar QF for which the PR-1 rate is not appropriate. In the past and prior to the development of the PR-2 rate, SCE&G for many years offered a PR-1 rate as well as an offer to negotiate a contract with any QF that did not qualify for the PR-1 rate. This response to PURPA worked satisfactorily for many years and SCE&G proposes to return to that arrangement for non-solar QFs of greater than 100 kW and up to 80 MW.

PR-1 RATE

Q. HOW DOES SCE&G COMPUTE THE AVOIDED ENERGY COMPONENT FOR SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. SCE&G uses the same methodology to estimate avoided energy costs for solar QFs on PR-1 as it did for solar QFs on PR-2. The only difference is the time period over which the avoided energy costs are estimated. The short-run avoided energy costs in the PR-1 rate are calculated for the period May 2019 through April 2020.

Q. WHAT IS THE AVOIDED CAPACITY COST COMPONENT FOR SOLAR QFs IN THE PR-1 RATE?

A. The avoided capacity cost for solar QFs subject to the PR-1 rate is zero. As explained with respect to the PR-2 rate, incremental solar QFs do not affect the resource plan and therefore avoid no future resources or their cost.

Q. HOW DOES SCE&G COMPUTE THE AVOIDED ENERGY COMPONENT FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. As discussed previously, SCE&G uses PROSYM to estimate the change in production costs that result from serving the base case load and the change case. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. The avoided costs are then accumulated into the four time-of-use periods described above. A non-solar QF would be paid based on how much energy it produces in each of these four time-of-use periods.

Q. HOW DOES SCE&G COMPUTE THE AVOIDED CAPACITY COMPONENT FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. Normally SCE&G would calculate its avoided capacity costs by taking the difference in avoidable costs between a base resource plan and a change case. However, because the PR-1 rate is designed for small QFs with a capacity rating of up to 100 kWs, SCE&G does not foresee that there will ever be enough capacity from these small non-solar QFs to affect its resource plan and, therefore, the avoided capacity costs for PR-1 are zero.

Q. WHAT ADJUSTMENTS ARE MADE TO THE AVOIDED COSTS IN THE PR-1 RATE?

A. The avoided energy cost results for both solar QFs and non-solar QFs are adjusted for line losses, working capital impacts, gross receipts taxes, and generation taxes. The Company made no adjustments to the avoided capacity costs for both solar and non-solar QFs under PR-1 because these costs are zero.

Q. WHAT IS THE RESULTING PR-1 RATE?

A. The avoided energy costs are shown in Table 3 below.

Table 3

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
May-April	0.03483	0.02939	0.03485	0.03384

Solar QFs ($/kWh)

Time Period	Year Round
May-April	0.03093

The avoided capacity costs for solar and non-solar QFs are zero.

CONCLUSION

Q. WHAT IS SCE&G REQUESTING OF THE COMMISSION IN THIS PROCEEDING?

A. SCE&G respectfully requests that the Commission approve the Company's proposed PR-1 and PR-2 Rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Developing a Resource Plan

Introduction

The following pages documents a study that was performed to assess cost of generation that could meet the resource plan needs of SCE&G's electric system. In each case generation is added over a thirty year horizon then modeled using SCE&G's hourly dispatch model. Costs are extrapolated for another ten years then the scenarios are compared using the scenario's 40-year levelized net present value. Generation is added to meet the winter base reserve level.

Reserve Margin

SCE&G's reserve margin policy is summarized in the following table. Peaking reserves are considered the capacity needed during the five highest peak load days in the season while base reserves are needed for the balance of the season.

SCE&G's Reserve Margin Policy		
	Summer	**Winter**
Base Reserves	**12%**	**14%**
Peaking Reserves	**14%**	**21%**
Increment for Peaking	**2%**	**7%**

SCE&G's generating resources serve both the base capacity need and the peak capacity need.

	Base MW Need		Peak MW Need	
Year	Summer	Winter	Summer	Winter
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	3
2023	0	0	0	30
2024	0	0	0	77
2025	0	0	0	128
2026	0	0	0	182
2027	0	0	0	229
2028	0	5	0	271
2029	0	51	0	274
2030	0	99	0	276
2031	0	147	0	279
2032	0	194	0	281
2033	45	242	0	284
2034	93	287	0	286
2035	141	332	0	288
2036	188	377	0	291
2037	235	425	0	293

These results show that it is the winter season requiring both base and peak capacity needs more so than the summer. In fact, with respect to the need for base capacity, the capacity added to meet the winter base need will also serve to meet the summer base need. Furthermore, there is no need for additional summer peaking resources. The derivation of these results is shown later in this report or in the appendix.

Meeting the Base Resource Need

For base resources the winter base reserve margin of 14% was used to determine the timing of adding generation resources. SCE&G created a list of 8 generating resources to be considered. The following table lists these resources. Please note that "CC" is shorthand for Combined Cycle, "ICT" is shorthand for Internal Combustion Turbine, and "PPA" is shorthand for Power Purchase Agreement.

Resource	**Capital Cost 2017$/kW**	**Description**
Battery #1	$2,126	100 MW with 400 MWH
Battery #2	$1,350	100 MW with 400 MWH, $1.65 MM/year in O&M
Solar Farm	$1,762	
CC 2-on-1	$876	1,081 MW with HR=6,203
CC 1-on-1	$938	540 MW with HR=6,276
ICT#1	$647	337 MW with HR=9,091
ICT#2	$697	93 MW with HR=9,169
Solar PPA	N/A	$30, $35, $40/MWh in 2018 esc. @2%

These 8 resources were combined in various ways to develop 19 resource plans, some of which consider the retirement of some existing generating units. The 19 scenarios are listed in the following table which is followed by a description of each scenario.

Scenario Number	Scenario
1	Battery-1
2	Battery-1 w/ Solar Ownership
3	Battery-2
4	Battery-2 w/ Solar Ownership
5	CC 1,081 MW
6	CC 540 MW + Retire Coal
7	CC 540 MW x 2
8	CC 540 MW w/ Battery-1
9	CC 540 MW w/ Battery-2
10	CC 540 MW w/ ICT 337 MW
11	CC 540 MW w/ ICT 93 MW
12	ICT 337 MW
13	ICT 93 MW
14	Solar Ownership w/ ICT 93 MW
15	Solar Ownership w/ ICT 93 MW + Retire Gas
16	Solar PPA 200 MW w/ ICT 93 MW, $30/MWh
17	Solar PPA 400 MW w/ ICT 93 MW, $30/MWh
18	Solar PPA 400 MW w/ ICT 93 MW, $35/MWh
19	Solar PPA 400 MW w/ ICT 93 MW, $40/MWh

Scenario 1: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 2: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $2,126/kW ($2017) with no annual cost. In this scenario 1,000 MW of solar generation is also added between 2028 and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 3: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year.

Scenario 4: In this scenario 1,000 MW of battery capacity is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $1,350/kW ($2017) with an annual cost of $1.65M per year. In this scenario 1000 MW of solar generation is added in 100 MW increments in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 5: In this scenario one 1,081 MW 2-on-1 combined cycle (CC) gas generating plant is added in the winter of 2029. This combined cycle generator has a full load heat rate of 6,203 Btu/kWh and an estimated construction cost of $876/kW ($2017).

Scenario 6: In this scenario three 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winter of 2029, 2033 and 2044. This scenario also includes the retirement of one 342 MW coal plant in the winter of 2029. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 7: In this scenario two 540 MW 1-on-1 combined cycle (CC) gas generating plants are added in the winters of 2029 and the winter of 2040. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017).

Scenario 8: In this scenario 100 MW of battery capacity is added in 2029 with two 540 MW 1-on-1 combined cycle (CC) gas generating plants added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The battery construction cost is $2,126/kW ($2017) but there is no annual operating cost.

Scenario 9: In this scenario 100 MW of battery capacity is added in 2029 with two 540 MW 1 on 1 combined cycle (CC) gas generating plants added in the winters of 2031 and the winter of 2042. These combined cycle generators have a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). Each battery installation has 100 MW of capacity and 400 MWhs of energy. The construction cost is $1,350/kW with an annual cost of $1.65M per year.

Scenario 10: In this scenario one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with two 337 MW ICT generators added in the winters of 2040 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 337 MW turbines have a full load heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 11: In this scenario one 540 MW 1-on-1 CC gas generating plant is added in the winter of 2029. The rest of the expansion plan is filled out with five 93 MW ICT generators added in the winters of 2040, 2042, 2044, 2046 and 2047. The combined cycle generator has a full load heat rate of 6,276 Btu/kWh and an estimated construction cost of $938/kW ($2017). The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 12: In this scenario three 337 MW internal combustion turbines (ICT) are added in the winters of 2029, 2036 and 2043. These turbines have a full load winter heat rate of 9,091 Btu/kWh and an estimated construction cost of $647/kW ($2017).

Scenario 13: In this scenario ten 93 MW internal combustion turbines (ICT) are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 14: In this scenario 1,000 MW of solar generation and 930 MW of ICTs are added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2047. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 15: In this scenario 1,000 MW of solar generation and 1,302 MW of ICT are added in years 2028(4), 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2043, 2045, and 2046. Three gas-fired steam plants are retired in the winter of 2028 with a combined capacity of 346 MW. The 93 MW turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017). The solar generators have no energy cost but a construction cost of $1,762/kW ($2017).

Scenario 16: In this scenario 200 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are prices at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 17: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $30/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 18: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs is priced at $35/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Scenario 19: In this scenario 400 MW of solar PPAs are added in 2026 which have no winter capacity. The energy of these PPAs are priced at $40/MWh in 2018 and growing at 2% per year. This scenario includes ten 93 MW ICTs added in years 2029, 2031, 2033, 2035, 2037, 2039, 2041, 2042, 2044, and 2046. These turbines have a full load heat rate of 9,169 Btu/kWh and an estimated construction cost of $697/kW ($2017).

Sensitivities and Results

The incremental revenue requirements associated with each of the 19 resource plans was computed using the PROSYM computer program to estimate production costs and an EXCEL capital model to calculate the associated capital costs. The EXCEL capital model combined the capital costs with the production costs to estimate total incremental revenue requirements over a 40-year planning horizon. Four sensitivities were considered: two on natural gas prices and two on the cost of CO_2 emissions. The four assumptions are 1) $0/ton CO_2 and base gas prices, 2) $15/ton CO_2 and high gas prices, 3) $0/ton CO_2 and high gas prices, and 4) $15/ton CO_2 and base gas prices. Base gas prices are based on NYMEX Henry Hub prices through 2020 then growing at 4.82% until 2031 then growing at 3.9% thereafter. High gas prices are double the base gas prices. The following table shows the ranking of each resource plan under each sensitivity. A ranking of 1 is the least cost option for the given assumptions.

		Scenario Ranking			
Scenario Number	**Scenario**	**$0 CO_2 Base gas**	**$15 CO_2 High gas**	**$0 CO_2 High gas**	**$15 CO_2 Base gas**
1	Battery-1	16	17	16	17
2	Battery-1 w/ Solar Ownership	19	18	19	19
3	Battery-2	11	13	12	15
4	Battery-2 w/ Solar Ownership	18	16	15	18
5	CC 1081 MW	14	14	14	11
6	CC 540 MW + Retire Coal	12	15	17	4
7	CC 540 MW x2	1	10	10	6
8	CC 540 MW w/ Battery-1	17	19	18	16
9	CC 540 MW w/ Battery-2	13	12	13	13
10	CC 540 MW w/ ICT 337 MW	8	9	8	8
11	CC 540 MW w/ ICT 93 MW	6	7	6	2
12	ICT 337 MW	9	11	9	10
13	ICT 93 MW	2	5	5	7
14	Solar Ownership w/ ICT 93 MW	10	6	7	12
15	Solar Ownership w/ ICT 93 MW + Retire Gas	15	8	11	14
16	Solar PPA 200 MW w/ ICT 93 MW ($30)	3	4	3	3
17	Solar PPA 400 MW w/ ICT 93 MW ($30)	4	1	1	1
18	Solar PPA 400 MW w/ ICT 93 MW ($35)	5	2	2	5
19	Solar PPA 400 MW w/ ICT 93 MW ($40)	7	3	4	9

Resource scenario #7 is the lowest cost resource plan under the assumption of $0 per ton of CO_2 emission and base gas costs. Scenario #17 is the lowest cost resource plan under the other three sensitivities. Because base gas prices is the most likely gas scenario and CO_2 costs are uncertain at this point, resource scenario #7 is the resource plan used in developing avoided costs and forecasting fuel costs.

Some Observations

The results above do not reflect a decision on the Company's part but only represent a snapshot at the present time and offer possible expansion plans under different sensitivities. More work on this issue will be done and based on the peak demand forecast SCE&G has time to do it. However, it is good to make some observations about these results to extract as much useful information as possible from the study. For example, under the $0 per ton CO_2 cost and base gas price scenario, resource plan #7 was the most economical. Cheaper energy provided by a new, highly efficient combined cycle plant when gas prices are relatively low without CO_2 emission costs offers enough economic benefit to overcome the extra capital costs.

Resource plan #13 is more economical than #12 under all four sensitivities suggesting than using the smaller ICT of 93 MW is better than using the larger ICT even though there is a higher capital cost and heat rate cost. The same conclusion can be drawn when comparing #11 to #10. Another possibility to consider in future studies involves the early retirement of coal units. Resource plan #6 falls fourth in the ranking when there is a $15 CO_2 emissions cost coupled with low gas prices. If gas prices were a little lower with respect to coal prices and the cost of CO_2 emissions a little larger, the retirement of coal units might prove to be an economical option.

Adding 100 MW batteries is consistently more expensive than adding 93 MW peakers. Compare scenario #11 with #9 and #14 with #4.

Resource scenario #17 was the most economical in three of the four sensitivities considered, i.e., whenever the gas price was high or there was a CO_2 emissions cost, the clean energy provided by more solar proved valuable to the system. Of course, there are two issues: 1) can solar energy be purchased at $30 per MWh escalating at 2%? and 2) can the system dispatch deal with the increase in operating issues caused by adding another 400 MW of solar to a system already dealing with over 1,000 MW of solar? As the system cost increases for solar PPA this scenario moves out of the least cost position, as seen in scenarios 18 and 19. SCE&G will continue to evaluate these and other scenarios in the future.

Meeting the Peak Resource Need

For peak resources the winter incremental peak reserve margin of 7% was used. The Company does not require any more summer peak capacity in large part because of all the solar energy currently on the system or under contract. Peak capacity is capacity needed to supplement base capacity on the five highest load days in the season. As was just discussed, the Company does not need additional base capacity until 2029 so until then there is extra base capacity to support the peak needs. With about 100 MW of demand response for peaking needs, significant additional peak capacity isn't required until 2023 or 2024. At present the Company is conducting a DSM Potential Study which will include demand response options for winter. When this study is complete, the Company will be able to choose the best way to meet its winter peaking needs.

APPENDIX

Table 1. Resource Scenario #7

SCE&G Forecast of Summer and Winter Loads and Resources - 2019 IRP Update

(MW)

	YEAR	2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4911	4999	4965	5069	5028	5129	5087	5187	5144	5243	5200	5301	5255	5360	5315	5420	5372	5482	5433	5544	5492	5602	5551	5663	5609	5724	5669	5783	5726	5845
2	EE/Renewables Impact	-28	-35	-32	-61	-49	-90	-68	-109	-86	-143	-116	-161	-131	-177	-145	-192	-159	-214	-176	-236	-195	-254	-211	-272	-227	-290	-243	-308	-259	-327
3	Gross Territorial Peak	4883	4964	4933	5008	4979	5039	5019	5078	5058	5100	5084	5140	5124	5183	5170	5228	5213	5268	5257	5308	5297	5348	5340	5391	5382	5434	5426	5475	5467	5518
System Capacity																															
4	Existing	5780	5948	5780	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	6295	6463	6295	6463	6295	6463	6295	6463
5	Existing Solar	121.1	0	193	0	379.8	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0	482	0
6	Demand Response	244	215	245	216	246	217	247	218	248	218	249	219	250	220	251	221	252	222	254	223	255	224	256	225	257	226	258	227	259	228
	Additions:																														
7	Solar Plant	71.93	0	186.8	0	102.1	0																								
8	Peaking/Intermediate																						540								
9	Baseload																														
10	Retirements	-85		-25																											
11	Total System Capacity	6132	6163	6380	6139	6483	6140	6484	6141	6485	6141	6486	6142	6487	6143	6488	6144	6489	6145	6491	6146	6492	6687	7033	6688	7034	6689	7035	6690	7036	6691
12	Winter Deficit		0		0		0		3		30		77		128		182		229		277		0		0		0		0		0
13	Total Production Capability	6132	6163	6380	6139	6483	6140	6484	6144	6485	6171	6486	6219	6487	6271	6488	6326	6489	6374	6491	6423	6492	6687	7033	6688	7034	6689	7035	6690	7036	6691
Reserves																															
14	Margin (L13-L3)	1249	1199	1447	1131	1504	1101	1465	1066	1427	1071	1402	1079	1363	1088	1318	1098	1276	1106	1234	1115	1195	1339	1693	1297	1652	1255	1609	1215	1569	1173
15	% Reserve Margin (L14/L3)	25.6%	24.2%	29.3%	22.6%	30.2%	21.8%	29.2%	21.0%	28.2%	21.0%	27.6%	21.0%	26.6%	21.0%	25.5%	21.0%	24.5%	21.0%	23.5%	21.0%	22.6%	25.0%	31.7%	24.1%	30.7%	23.1%	29.7%	22.2%	28.7%	21.3%

Table 2. Resource Scenario #17

SCE&G Forecast of Summer and Winter Loads and Resources - 2019 IRP Update
(MW)

	YEAR	2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	4911	4999	4965	5069	5028	5129	5087	5187	5144	5243	5200	5301	5255	5360	5315	5420	5372	5482	5433	5544	5492	5602	5551	5663	5609	5724	5669	5783	5726	5845
2	EE/Renewables Impact	-28	-35	-32	-61	-49	-90	-68	-109	-86	-143	-116	-161	-131	-177	-145	-192	-159	-214	-176	-236	-195	-254	-211	-272	-227	-290	-243	-308	-259	-327
3	Gross Territorial Peak	4883	4964	4933	5008	4979	5039	5019	5078	5058	5100	5084	5140	5124	5183	5170	5228	5213	5268	5257	5308	5297	5348	5340	5391	5382	5434	5426	5475	5467	5518
System Capacity																															
4	Existing	5780	5948	5780	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5755	5923	5848	6016	5848	6016	5941	6109	5941	6109
5	Existing Solar	121.1	0	193	0	379.8	0	482	0	482	0	482	0	482	0	482	0	482	184	482	184	482	184	482	184	482	184	482	184	482	184
6	Demand Response	244	215	245	216	246	217	247	218	248	218	249	219	250	220	251	221	252	222	254	223	255	224	256	225	257	226	258	227	259	228
	Additions:																														
7	Solar Plant	71.93	0	186.8	0	102.1	0										184														
8	Peaking/Intermediate																						93				93				93
9	Baseload																														
10	Retirements	-85		-25																											
11	Total System Capacity	6132	6163	6380	6139	6483	6140	6484	6141	6485	6141	6486	6142	6487	6143	6488	6328	6489	6329	6491	6330	6492	6424	6586	6425	6587	6519	6681	6520	6682	6614
12	Winter Deficit		0		0		0		3		30		77		128		0		45		93		47		98		56		105		63
13	Total Production Capability	6132	6163	6380	6139	6483	6140	6484	6144	6485	6171	6486	6219	6487	6271	6488	6328	6489	6374	6491	6423	6492	6471	6586	6523	6587	6575	6681	6625	6682	6677
Reserves																															
14	Margin (L13-L3)	1249	1199	1447	1131	1504	1101	1465	1066	1427	1071	1402	1079	1363	1088	1318	1100	1276	1106	1234	1115	1195	1123	1246	1132	1205	1141	1255	1150	1215	1159
15	% Reserve Margin (L14/L3)	25.6%	24.2%	29.3%	22.6%	30.2%	21.8%	29.2%	21.0%	28.2%	21.0%	27.6%	21.0%	26.6%	21.0%	25.5%	21.0%	24.5%	21.0%	23.5%	21.0%	22.6%	21.0%	23.3%	21.0%	22.4%	21.0%	23.1%	21.0%	22.2%	21.0%